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Fast Approach to Manage Depletion of Naturally Fractured Carbonate Gas Reservoir with Water Rising Issue through Fracture Networks

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Abstract

Gas resources play a vital role in nowadays energy supply. It is providing 24 percent of all energy used in our diverse energy portfolio and it is important to recover as much gas as possible. Water rising through fracture networks is one of main issues in naturally fractured gas reservoirs that causes gas trapping in matrix blocks and water production and subsequent recovery reduction. From Economic point of view it imposes high operating expenses, environmental risks, and productivity reduction.
Although numerical simulations can address relatively complex water rising problem, they usually are time consuming, and encounter difficulties in computational efficiency. A fast and appropriate decision making method is required to provide an immediate action to manage reservoir depletion where water rising is a serious challenge. This study introduces a fast approach to investigate the efficiency of common production strategies for managing depletion of naturally fractured carbonate reservoir when it has water rising issue through fracture networks. This approach was implemented to one real field which has currently encountered rapid water rising during production.

Keywords: *Gas reservoir; Fractured; Water rising; Recovery; Depletion management.*

1. Introduction

Gas reservoirs are classified into two groups according to their drive mechanisms; depletion-drive or water-drive [1]. Water-drive gas reservoirs are bounded by and in communication with aquifers. During reservoir depletion, the compressed waters within the aquifers expand into the gas reservoir and mitigate the pressure decline [2]. This water expansion in naturally fractured reservoirs, particularly with low matrix permeability fills up the fractures and the free gas will stop to flow and water would be the only fluid passing through the fractures and early breakthrough happens [3]. This snaps off of the gas phase in the matrix block invaded by water and results in residual or trapped gas left behind in the fractures [4]. Moreover, the great amount of produced water from gas wells boosts liquid loading and leads to the additional pressure loss in the borehole significantly [1]. As a result, the gas recovery of these reservoirs is low. Beaver River Field of Canada [5], Dengying gas reservoir in Weiyuan gas Field in China [1] and Aguarague Field in Argentina [6] with the gas recovery of 12, 37 and 34 percent respectively are examples of these kinds of reservoirs .

Excess water production imposes high operating expenses, environmental risks, and productivity reduction problems affecting wells (drainage area, completion, and artificial lift) and facilities. This is why various techniques and approaches have been applied to cope with this issue [7-9].

There are various techniques and procedures which have been proposed and applied to cope with water invasion. These techniques can be classified as well based, reservoir based and surface facility based. Reviewing the literature, reservoir based techniques which are suitable candidates for treating water invasion in the naturally fractured water drive gas reservoirs are the subjects of many researches.

Agarwal [10] demonstrated that producing at as high as possible, resulted in a significant increase in gas reserves by lowering the abandonment pressure through material balance calculation. Knapp *et al.* [11] by developing a two-phase two-dimensional model showed that gas recovery increases with decreasing aquifer strength and increasing production rate. 30 percent increase in RF of Katy gas reservoir through accelerated blowdown gas production was confirmed by Lutes *et al.* [12] using tank type model. Pepperdine [13] used a mathematical model to investigate the performance of the water drive Devonian gas field in north eastern British Colombia and concluded that the depletion rate should be increased as much as possible to achieve maximum gas recovery. Brinkman [14] reported that accelerated blowdown of up to 115 MMSCF/D from a water drive gas reservoir in U.S. gulf coast resulted in a 20% rise in remaining recovery factor versus continued low-rate depletion. Simulation study of Soehlingen Schneverdingen water drive gas reservoir by Cohen [15] illustrated that the acceleration of production appears to increase the ultimate recovery only slightly (2.3% GIP). He believed that it is not an optimum gas rate to significantly lower the gas-cap pressures before the water front reaches the existing wells. Moltz [16] showed that material-balance calculations need to be modified to account for trapped-gas compression that occurs with repressuring, and demonstrated the use of a "simple" numerical simulation model to predict performance to match reservoir behavior successfully and quantifying the effects of trapped-gas compression, and to identify the importance of critical gas rates and timing for optimizing reserve recovery from this repressuring water drive gas reservoir. Sech *et al.* [17] simulated the effect of production rate on recovery factor in horizontal wells through three dimensional model. They found that increasing the production rate is not a good strategy for gas reservoirs with high vertical to horizontal permeability and strong aquifer because the water breakthrough occurred regardless of the production rate at which the well produced. Rezaee *et al.* [18] investigated the optimum accelerating production rate from water drive gas reservoirs in laboratory scale systems and its upscaling in reservoir. Naderi *et al.* [19] investigated the various factors affected the optimization and economic production from water drive gas reservoirs which played an important role in designing an effective reservoir development plan. They confirmed that suitable production rate is a main factor in increasing the RF of water drive gas reservoirs. Meomen *et al.* [20] investigated the success of blow down approach on a heterogeneous reservoir through simulation to optimize the gas production.

Rogers [21] and Arcaro and Bassiouni [22] reported the advantages of co-production of gas and water at the same time (gas is produced from up-dip wells while water is produced from down-dip wells) and this method proposed for moderate to active water drive gas reservoirs especially for reservoirs that are not yet watered out. Simulation study by Cohen [15] also determined coproduction strategies in Soehlingen Schneverdingen water drive gas reservoir. The results confirmed that the production of water in is beneficial to gas production in other wells because it slows the water advance to these wells. An improvement in the ultimate recovery was 3.6% GIP compared with the base case. Co-production is also recommended by Bassiouni [23] but he pointed out that water production can be uneconomical for strong water drive gas reservoirs. Ping *et al.* [24] analyzed the relevant methodologies for enhancing the recovery of gas reservoirs, and proposed the suggestions about enhanced gas recovery(EGR) technology development, which provides a basis for EGR measures in fields. In that study water withdraw is one of the main EGR techniques. Meomen *et al.* [20] and Maselugbo [25] investigated the success of coproduction approach on a heterogeneous reservoir through simulation to optimize the gas production. Yeger *et al.* [26] by simulation and economic analysis investigated the feasible alternatives (infill drilling, variable production, and co-production) for revival of the Alaskan water drive gas reservoir and commercialization of the produced gas and their results showed that the co-production is the best method to overcome water influx invasion.

Xi *et al.* [27], Xueqing *et al.* [28] and Wan and Su [29] summarized the experience with gas dewatering techniques and methods in naturally fractured gas pools in South-Sichuan gas sector, including pilot tests at individual wells and field wide applications in entire gas reservoirs at both initial geopressured and late pressure-depleted development phases. In South-Sichuan gas sector natural gas is mainly stored in matrix media, and fractures are the primary channels for fluid flow toward the wellbores and communication with aquifer. In this investigation apart from many well based gas dewatering techniques which applied successfully, reservoir based strategies like accelerated blowdown, co-production and cyclic gas production reported as effective techniques for RF improvement in this water drive naturally fractured gas sector.

Pow *et al.* [3] investigated the cyclic gas production in tight naturally fractured gas reservoirs with active water drive gas in southern Alberta foothills in laboratory scale systems and up-scaled their results on a real field to predict the amount of excess gas production through cyclic gas production . They showed that the best strategy for these type of reservoirs is that wells are produced at the highest possible rates until the water breakthroughs, and followed by a shut–in period of perhaps several years to allow gas to re-accumulate.

Reviewing the literature reveal that accelerated blowdown, coproduction, and cyclic gas production are relatively the most successful reservoir based techniques to cope with water invasion in water drive naturally fractured gas reservoirs.

Efficiency of aforementioned reactive techniques needs to be quantified to help decision making process. Reviewed studies usually focused on one treatment method through standalone reservoir simulation without considering the economic evaluation and tried to conclude the efficiency of proposed technique regarding improvement of gas recovery factor. Sometimes authors tried to make simplified conceptual model or in the case of reservoir simulation they spent a lot of time to model, history match and simulate the reservoir. This amount of time may jeopardize reservoir life particularly in water drive naturally fractured carbonate gas reservoir with severe water rising issue. In this study, a novel methodology is introduced which enables quick evaluation of different techniques regarding improvement of RF along with economic evaluation for selecting the best one for water rising problem in naturally fractured gas reservoirs considering the interaction of reservoir model to surface through integrated asset modeling (IAM). The value of such a model is its ability to predict, plan and optimize the hydrocarbon recovery and production with as much accuracy and precision as possible. The developed approach is applied to field X which is a carbonate fractured gas reservoir in Iran that has severe water rising issue.

2. Methodology

To evaluate the applicability of different strategies for management of water rising issue, and to select the optimum one, a reliable reservoir model is required. Numerical reservoir model construction in the fractured reservoirs is not straightforward and it is time consuming which jeopardizes the field life where immediate water management action is required. This section introduces a stepwise approach to investigate the efficiency of current production strategies for a water drive naturally fractured gas reservoir. It should be noted that this approach is only applicable for the reservoirs with good pressure connectivity.

Figure 1 shows the developed workflow for decision making about water rising issue. As the flow chart indicates there are three main phases of history, prediction scenarios and economic analysis. In the history phase, an analytical reservoir model is developed by Mbal, and then it is history matched. It should be noted that aquifer and reservoir are modeled separately as multi-tank with transmissibility. Once a history match is achieved, the amount of water influx from the aquifer to the reservoir is obtained versus time.

Based on the observed Gas Water Level (GWL) changes during the production life of the field, corresponding Water Influx (WI) is obtained from Mbal model. Regarding the bulk volume (Vb) of the reservoir (from static model or any available data from structural geology and geophysics) between initial Gas Water Contact (GWC) and each detected GWL, amount of swept porosity (virtual porosity of the region invaded by water, Φsw) is calculated by equation 1. The estimated average swept porosity is used in the prediction scenarios phase for calculating the amount of water influx corresponding to Maximum Allowable GWL (MAGWL). This level is determined by fact of having most wells as active in long period of time, petrophysical data and considering coning issue. When water reaches this level, the reservoir cannot produce desired gas. This level is considered as a limitation in prediction phase.

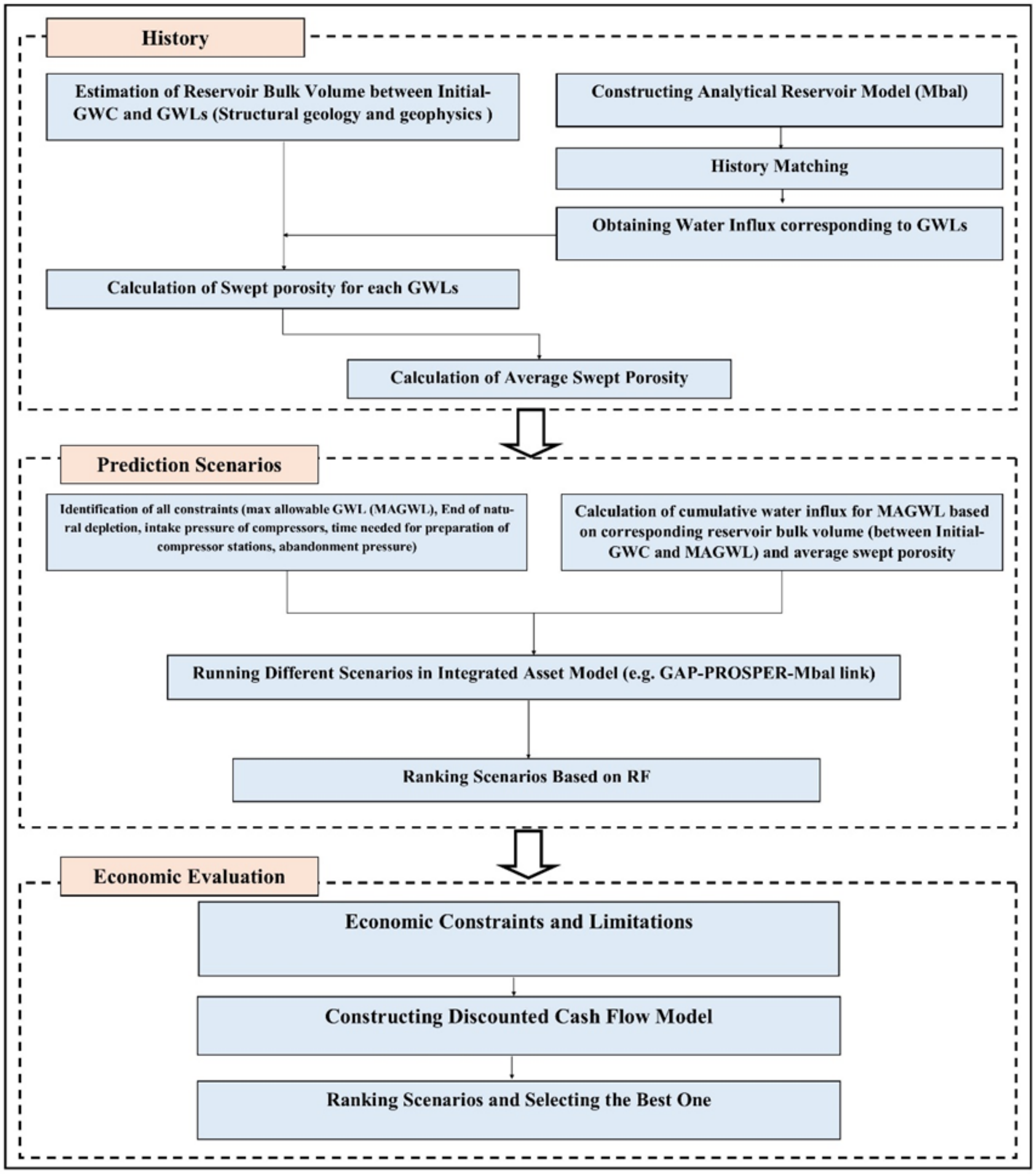

Figure 1. Workflow of evaluation of water rising issue in gas reservoirs

$$\Phi sw = WI/Vb \qquad (1)$$

Regarding the average swept porosity and bulk volume of the reservoir between initial GWC and MAGWL, the amount of corresponding water influx is calculated by equation 2.

$$WI = Vb * \Phi sw \qquad (2)$$

The constructed Mbal model is linked to the well and surface models to consider the interactions of the reservoir, well and surface facility in the prediction phase as integrated asset modeling. Apart from MAGWL as a limitation, some other limitations must be considered in the prediction phase including the end of natural depletion, intake pressures of compressors, time needed for preparation of compressor stations, and abandonment pressure. Relevant production scenarios are investigated through the integrated model by considering all mentioned constraints. At the final stage of the prediction phase, since there are a lot of production scenarios and it is difficult to do economic analysis for all of them, production scenarios with the highest Recovery Factor (RF) are selected for economic analysis.

In the economic phase, Capital Expenditure (CAPEX), Operational Expenditure (OPEX), and Net Present Value (NPV) are calculated for selected scenarios, and the best scenario is selected based on the highest NPV.

3. Case study

The developed approach is applied to Field X which is a natural fractured gas reservoir. The water rising through fracture networks is a serious challenge in this field. Field X was discovered in 2000 and it has three reservoir formations. The anticline is nearly symmetric and has about 50 × 12 km at the surface and 37×5 km on top of B formation with 1000 m vertical closure. Up to May 2018, 21 wells were drilled and completed in different formations in the field. Reservoir properties are summarized in Table 1.

Table 1. Reservoir properties

Initial reservoir pressure (psig)	3267
Reservoir pressure (psig) (2018-1-12)	2458
Cumulative gas production (TSCF)	2.09
Initial gas in place (TSCF)	5.34
RF up to 2018-1-12	39.18
Initial water contact (meter subsea (mss))	1670
Reservoir Temperature (F) @1500mss	190

Based on the analysis of the fluid sample from different formations, static tests, mud loss, geology, and geophysics interpretation, the reservoir is highly fractured with areal and vertical connectivity within the reservoir. Moreover, the estimated GWL was similar in different wells at the same time which is another indication of high connectivity within the reservoir.

Gas production from the field was initiated in 2007 with field plateau rate of 18MMm^3/day and the first evidence of water rising through fractures was observed in 2013. Later on, most producing wells have faced this issue. Many treatments like choking back, plugging back and perforating new intervals were performed, however, these solutions were not permanent and the plateau rate of the field was being reduced despite increasing the number of wells. Losing a long production interval was another consequence of this problem. Moreover, if this problem is not managed quickly and water is produced at the surface, the water makes sever slugging in low points of flow lines due to its complexity in mountain area.

To perform quick studies and immediate action for managing the water rising, relevant production strategies related to this kind of reservoir is investigated through the proposed approach.

4. Results and discussion

4.1. History

Field "X" has good areal and vertical connectivity and it can be considered as a reservoir tank. The analytical reservoir model was constructed and it was history-matched in Mbal. Figure 2 shows reservoir tank pressure versus the calculated cumulative gas production. The red curve indicates the case without aquifer and the blue with the aquifer. The result indicates the presence of a weak aquifer with high transmissibility to the reservoir due to the fractures.

Table 2. Water influxes and bulk volume between GWC and GWL in each year in field "X"

GWL	Depth (mss)	Water influx from MBAL (MMSTB)	Total swept bulk by water (MMSTB)	Average total swept porosity (fraction)
Initial GWC	1670	0	0	0
GWL-2012-6-13	1549	518	70429	0.0074
GWL-2013-5-16	1518	620	86405	0.0072
GWL-2014-8-7	1502	747	94331	0.008
GWL-2015-5-3	1493	821	98696	0.0083
GWL-2016-5-12	1471	923	109074	0.0085
GWL-2017-4-11	1455	1003	116365	0.0086
GWL-2017-8-11	1440	1026	122994	0.0083
GWL-2018-1-12	1435	1052	125158	0.0084

Reservoir bulk volumes between initial GWC and observed GWLs are estimated through approximate structural model. Based on the observed GWLs from static pressure measurements in different time steps during production, the corresponding aquifer influxes are calculated from Mbal. Calculated water influx, bulk volume, and average swept porosity (calculated from equation 1) during production (from 2012 to 2018) are presented in Table 2. The average swept porosity (matrix and fracture) from 2012 up to 2018 is estimated as 0.84%.

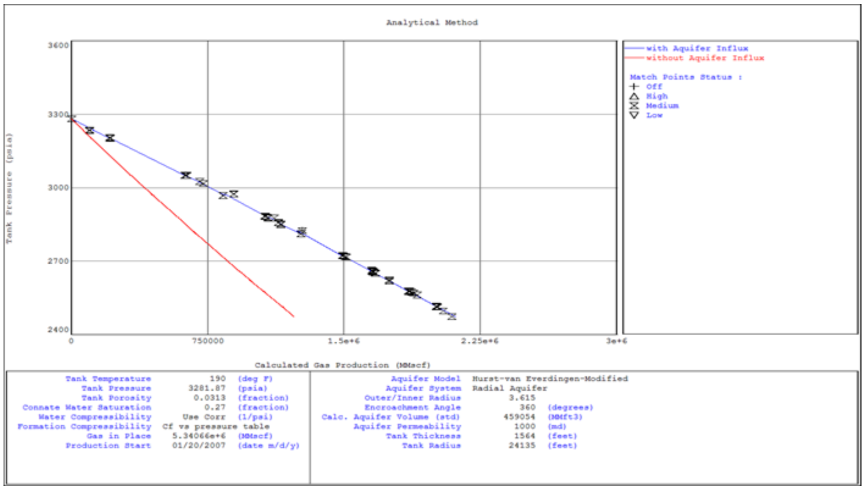

Figure 2. Mbal history-matched model of field "X"

4.2. Prediction scenarios

The structural model provides corresponding bulk volumes at each predicted GWLs in the future production. This parameter and the calculated average swept porosity are used to estimate the cumulative water influxes by equation 2. Table 3 shows the bulk volume and amount of water influx corresponding to each future GWLs.

Table 3. Bulk volume and amount of water influx corresponding to each future GWLs

	GWL (mss)	Calculated cumulative water influx (MMSTB)	Bulk volume between initial GWC and GWLs (MMSTB)	Average swept porosity (fraction)
GWL-2018-1-13	1435	1052 (Mbal)	125158	
Prediction	1370	1270	151167	0.0084
	1367	1279	152268	
	1270	1548	184259	
	1250	1596	189976	

Based on petrophysical study, MAGWL is chosen at 1250 mss with consideration of conning issue and most wells being on production with low water problem. Amount of water influx at this depth is 1596 MMSTB and it is considered as an initial constraint in investigating any technical scenario in this field.

Maximum possible gas production rate from current wells (21 wells) is 17 MMm3/d. The minimum gas pressure at slug catcher must be about 102 barg for end of natural depletion. First and second stage compressors are planned to be installed with range of intake pressure of 50-76 and 19-31 bar respectively. For scenarios of co-production of gas and water, water is produced from aquifer by water production wells with rate of 15 MSTB/d by using ESP. Moreover, four years are needed for field owner to prepare compressor stations. In fact, natural depletion should take at least four years and other strategies are applied and investigated after this duration.

By considering the explained constrained and calculated values in previous section, the integrated asset modeling is utilized to rank the different scenarios for water rising management. The accelerated blow down and coproduction strategies are considered for this case study. The cyclic gas production is not investigated due to the operator limitations (they are not allowed to shut-in the field). In cyclic gas production the field must be shut–in perhaps for several years to allow gas to re-accumulate. A combination of different gas production rates and water production rates from aquifer are considered and compared (Table 4) through integrated asset modeling. Figure 3 depicts the constructed integrated model which considers the effect of all including parameters from reservoir, well and surface facility.

Table 4. Gas and water production rates considered in this study

Gas production rates MMm^3/d	5	8	10	12	13	14	15	16	17	20
Water production rates MSTB/d	0	15	45	90	150	210	300	480		

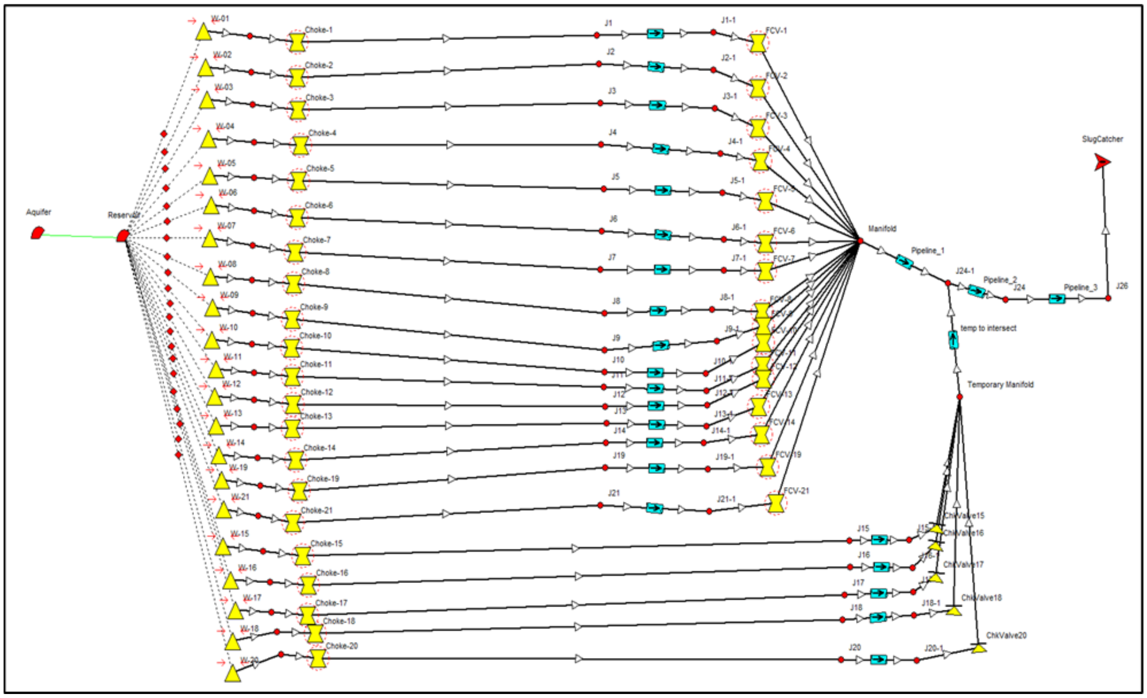

Figure 3. Integrated Model of X Field

Table 5 shows the duration of natural depletion for different production rates. The best production rate during natural depletion is 10 MMm3/day since it is highest rate that has four-year duration for natural depletion which gives enough time to field owner to provide compressor stations. RF for this rate at the end of natural depletion is 49.2%.

Table 5. Duration of natural depletion for different field gas rates

Rate (MMm^3/d)	End of natural depletion	Duration of natural depletion from 2018-1-12
5	12-5-2021	3 years- 4 months
8	12-12-2022	4 years- 11 months
10	12-3-2022	4 years- 2 months
12	12-6-2020	2 years- 5 months
13	12-7-2020	2 years- 6 months
14	12-6-2020	2 years- 5 months
15	12-4-2020	2 years- 3 months
16	12-8-2019	1 years- 7 months
17	12-10-2018	9 months
20	From q=17	Need compressor urgently

Table 6 presents a number of the highest RF scenarios with and without water production which are evaluated in this study. The first number in each scenario is the production plateau rate during natural depletion which is equal to 10 MMm^3/d for all scenarios, the second number is the gas production rate after natural depletion in MMm^3/d and the third number is water production rate (MSTB/d) after natural depletion duration. As this table indicates increasing the production rate is not helpful since RF does not increase considerably. Installing the first stage compressors after the natural depletion, increases the recovery factor by approximately 10 %. Moreover, there is no need for installation of second stage compressors since the GWL reaches 1250mss before reservoir pressure drops to its threshold limit for installation of second stage compressors. Table 6 also shows the recovery factor at different gas production rates in X field by considering the co-production of gas and water. It indicates that the water production from aquifer can improve the RF to more than 80 %.

Table 6. Results of the ranked scenarios based on recovery factor

Production scenarios	RF (%)	Production strategy
Qg10-10-Qw0	58.89	Accelerated blow-down
Qg10-12-Qw0	58.99	
Qg10-13-Qw0	59.09	
Qg10-14-Qw0	59.15	
Qg10-15-Qw0	59.20	
Qg10-16-Qw0	59.25	
Qg10-17-Qw0	59.30	
Qg10-20-Qw0	59.35	
Qg10-10-Qw210	82.42	Co-production of gas and water
Qg10-10-Qw300	81.29	
Qg10-12-Qw300	80.36	
Qg10-13-Qw300	80.68	
Qg10-13-Qw390	80.45	
Qg10-12-Qw420	80.03	
Qg10-10-Qw480	80.49	

4.3. Economic evaluation

Discounted cash flow model (DCFM) is built to find the best economic production scenario. OPEX and CAPEX are estimated by considering the suitable economic parameters for any production scenarios and the NPV is used as the objective function. The economic parameters and their values are shown in Table 7. In the economic evaluation, it is assumed that drilling the two wells per year is reachable if it is required. The best scenarios based on the NPV values are presented in Table 8. For accelerated blowdown, the Qg10-10-Qw0 has the highest NPV and the optimum production rate during and after natural depletion period is 10 MMm3/d. Detailed results of this scenario are summarized in Table 9.

Table 7. Economic parameter assumptions

Gas Price ($\$/m^3$)	0.2
Compressor-stage1 (MM$/ for 1 MMm^3/d) with standby	9
Compressor-stage2 (MM$/ for 1 MMm^3/d) with standby	6
OPEX (compressor) (MM$/ for 1 MMm^3/d per Year)	0.6
Discount rate (%)	10
Well price (MM$/well)	15
Pump price (MM$)	1
OPEX (pump) (MM$/Year)	0.5
Water production rate (MSTB/d per well)	15

Table 8. NPV of the best scenarios

Production scenarios	RF (%)	NPV(MM$)	Production strategy
Qg10-10-Qw0	58.89	4186	Accelerated blowdown
Qg10-12-Qw0	58.99	3944	
Qg10-13-Qw0	59.09	3970	
Qg10-14-Qw0	59.15	4002	
Qg10-15-Qw0	59.20	4030	
Qg10-16-Qw0	59.25	4045	
Qg10-17-Qw0	59.30	4067	
Qg10-20-Qw0	59.35	4077	
Qg10-10-Qw210	82.42	5671	Co-production of gas and water
Qg10-10-Qw300	81.29	5564	
Qg10-12-Qw300	80.36	5817	
Qg10-13-Qw300	80.68	5961	
Qg10-13-Qw390	80.45	5913	
Qg10-12-Qw420	80.03	5755	
Qg10-10-Qw480	80.49	5466	

Table 9. Detailed results of Qg10-10-Qw0

Qg10-10-Qw0	End of natural depletion	End of first stage compressors
Time (End of History = 2018-1-12)	2022-3-7	2026-3-27
Reservoir Pressure (psig)	2207	1931
RF (%)	49.20	58.99
Water Influx (MMSTB)	1326	1596
GWL (mss)	1345	1250
Total Time (years)	4	4
10 % RF increase vs. natural depletion	Cumulative gas production increase($MMMm^3$)= 15.1	NPV(MM$)= 2314 (Natural) NPV(MM$)= 4186 (With compressor) NPV(MM$) = 1872 (Difference)

In co-production of gas and water approach, Qg10-13-Qw300 has the highest NPV value . Qg of 10 MMm^3/d during natural depletion and Qg of 13 MMm^3/d afterwards. Producing water from aquifer starts after natural depletion and increase gradually (two water wells added each year) to 300 MSTB/d. Table 10 shows the detailed results of this approach.

Table 10. Detailed results of Qg10-13-Qw300

Qg10-13-Qw300	End of natural depletion	End of first stage compressors	End of second stage compressors
Time (end of history = 2018-1-12)	2022-3-7	2029-11-17	2032-3-17
Reservoir pressure (psig)	2207	1273	943
RF (%)	49.2	73.36	80.68
Water Influx (MMSTB)	1326	1599	1591
GWL (mss)	1345	1256.5	1256
Total Time (years)	4	7.5	2
21.69 % RF increase vs. Qg10-10-Qw0	Cumulative gas production increase($MMMm^3$)= 32.8	NPV(MM$)= 4186 (With compressor) NPV(MM$)= 5961 (With compressor and water production) NPV(MM$) = 1775 (difference)	

4.4. Water gas level at the end of the best scenarios

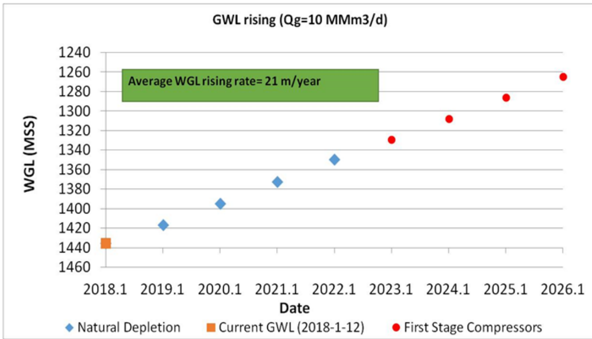

Figure 4. Integrated model of X field

Water gas level in reservoir is calculated based on workflow presented in Figure 2 for each year of prediction. Figure 4 shows the trend of GWL during the natural depletion and afterward for Qg10-10-Qw0. The trend is approximately the same in all intervals and GWL reaches 1250 mss.

Figure 5 shows the trend of GWL change during natural depletion and afterward for Qg10-13Qw300. By starting the water production from aquifer the stable rate of GWL rising decreases considerably until to stabilize nearly at 1260 mss.

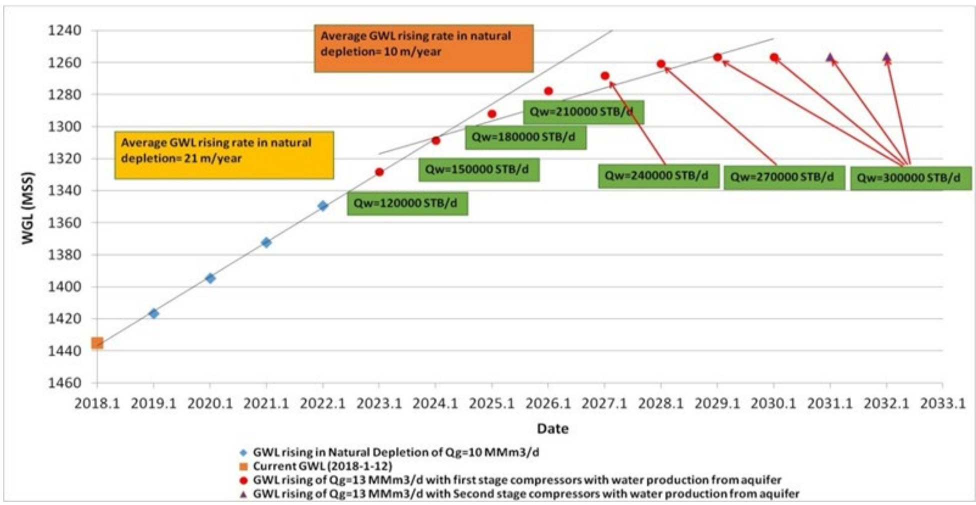

Figure 5. GWL rising (Qg10-13-Qw300)

5. Conclusion

Water invasion through fracture networks is one of main issues in water drive naturally fractured gas reservoirs. This water expansion in naturally fractured reservoirs fills up the fractures and the free gas will stop to flow and water would be the only fluid passing through the fractures, results in early water breakthrough, recovery reduction and it imposes high operating expenses and environmental risks.

In this study, a stepwise approach is introduced which enables evaluation of relevant techniques deal with managing reservoir depletion in water drive naturally fractured gas reservoirs. Apart from its simplicity, this approach regards the interaction of reservoirs, wells and surface facilities models which is more reliable in computation of recovery since all constraints from reservoir to surface can be considered simultaneously. In addition, tank type reservoir model instead of complicated numerical reservoir model helps to take more immediate water management action when water invasion jeopardizes the field life. Moreover, improvements in recovery factor is not the sole making decision criteria and production scenarios with high ranked RF evaluated economically to select the best scenario.

This methodology was implemented for a real case of the same problem. Through which effect of accelerated blowdown and coproduction of water and gas was evaluated.

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